APPENDIX C

2002 AUDITED FINANCIAL STATEMENTS OF THE DEPARTMENT

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City of Seattle – City Light Department

Financial Statements for the Years Ended December 31, 2002 and 2001, and Independent Auditors' Report

CITY OF SEATTLE – CITY LIGHT DEPARTMENT

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INDEPENDENT AUDITORS' REPORT

Superintendent
City of Seattle – City Light Department
Seattle, Washington

We have audited the accompanying balance sheets of the City of Seattle – City Light Department (the "Department") as of December 31, 2002 and 2001, and the related statements of revenues, expenses, and changes in equity and of cash flows for the years then ended. These financial statements are the responsibility of the Department's management. Our responsibility is to express an opinion on the financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Department as of December 31, 2002 and 2001, and the changes of its equity and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

As described in Note 1 to the financial statements, in fiscal year 2002, the Department adopted Governmental Accounting Standards Board ("GASB") Statement No. 34, *Basic Financial Statements—and Management's Discussion and Analysis—for State and Local Governments*; GASB Statement No. 37, *Basic Financial Statements—and Management's Discussion and Analysis—for State and Local Governments: Omnibus—an Amendment of GASB Statements No. 21 and No. 34*; and GASB Statement No. 38, *Certain Financial Statement Note Disclosures*.

The management's discussion and analysis on pages 2 through 10 is not a required part of the basic financial statements but is supplementary information required by the Governmental Accounting Standards Board. We have applied certain limited procedures, which consisted principally of inquiries of management regarding the methods of measurement and presentation of the supplementary information. However, we did not audit the information and express no opinion on it.

Deloitte & Touche LLP

April 18, 2003

Deloitte
Touche
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CITY OF SEATTLE – CITY LIGHT DEPARTMENT

MANAGEMENT'S DISCUSSION AND ANALYSIS
DECEMBER 31, 2002

The following discussion and analysis of the financial performance of the City of Seattle – City Light Department (the "Department") provides a summary of the financial activities for the year ended December 31, 2002. This discussion and analysis should be read in combination with the Department's financial statements, which immediately follow this section.

RESULTS OF OPERATIONS

Condensed Revenues and Expenses

Year ending December 31,	2002	2001
Operating revenues	$ 709,330,439	$ 632,453,970
Nonoperating revenues	10,467,972	13,275,220
Total revenues	719,798,411	645,729,190
Operating expenses	650,574,759	657,656,814
Nonoperating expenses	84,057,713	76,708,493
Total expenses	734,632,472	734,365,307
Capital contributions	10,631,017	12,489,627
Grants and transfers	2,337,759	2,806,083
Net loss	$ (1,865,285)	$ (73,340,407)

The Department recorded a net loss of $1.9 million in 2002, compared with a net loss of $73.3 million in 2001. Financial results in 2001 reflected the deferral of $300.0 million in power costs incurred in that year; in 2002 $100.0 million of the deferred power costs were amortized. Without the deferral and amortization of power costs, the net loss in 2001 would have been $373.3 million, and net income of $98.1 million would have been realized in 2002.

The improvement in the Department's financial results from 2001 to 2002 was heavily influenced by increases in retail rates that were enacted in 2001, the return of more normal water conditions to the Northwest region following the 2000 – 2001 drought, and the availability of additional power through purchased power contracts. As a result of these resource acquisitions and favorable water conditions, the Department generated substantial revenue from the sale of surplus power in the wholesale market.

OPERATING REVENUES

Operating revenues totalled $709.3 million in 2002, an increase of $76.9 million, or 12.2%, from the prior year. Significant increases were recorded in both retail and wholesale revenues. These increases were partially offset by a net decrease in other power-related revenues.

Revenue from the sale of power to retail customers in the Department's service area increased from $503.4 million in 2001 to $562.4 million in 2002, an increase of $59.0 million, or 11.7%. The increase in revenue is attributable to the rate increases that were implemented in stages in 2001 and that were in effect throughout

2002, with only minor adjustments. Rates for nonresidential customers in the downtown network area were increased in March 2002. Rates for all classes were lowered by an average of 1.1% on April 1, 2002, to pass through decreases in the power rates charged by the Bonneville Power Administration ("Bonneville"). The volume of energy sold in 2002 was actually 0.8% lower in 2002 than in 2001, due to the effects of warm winter temperatures and high rates.

Revenue from the sale of surplus energy in the wholesale market increased from $73.9 million in 2001 to $112.8 million in 2002, due to a large increase in the volume of energy sold. Energy sold in the wholesale market increased from 468,827 megawatt hours ("MWh") in 2001 to 4,647,945 MWh in 2002; however, the average price realized on these sales declined sharply, from $157.63 per MWh in 2001 to $24.27 in 2002. The result of these two offsetting changes was an increase of $38.9 million, or 52.6%, in wholesale revenue. Wholesale purchases are discussed below in the section dealing with power and transmission costs.

Other power-related revenues declined from $44.3 million in 2001 to $21.1 million in 2002, a decrease of $23.2 million. The value of energy delivered to other utilities under exchange agreements decreased from $31.7 million in 2001 to $5.3 million in 2002. Exchanged energy is valued at the blended weighted-average cost of power to the Department for the periods when the exchanges take place. This value declined sharply from 2001 to 2002. In addition, the amount of energy delivered under exchange agreements was lower in 2002. Similarly, the value of energy delivered under basis transactions declined from $6.9 million in 2001 to $2.2 million in 2002, reflecting both a decrease in deliveries and a lower unit value per MWh delivered. Revenue from sales of transmission and reserves fell from $3.2 million in 2001 to $2.2 million in 2002. The decline in revenue in these categories was partially offset by revenue from new sources. The Department's contract with Bonneville that took effect on October 1, 2001, provides credits for investments in conservation and renewable resources. These credits amounted to $2.1 million in 2002. Revenue from integration and exchange services provided to Pacific Power Management in connection with the purchase of energy from the State Line Wind Project amounted to $2.8 million. The Department recognized $3.3 million in revenue associated with payments received from Bonneville for the purchase of conservation savings. The Department expects to receive $26.7 million from Bonneville in 2002 and 2003 in payments for the purchase of conservation savings. These payments will be recognized as revenue in equal monthly amounts of $222,178 over the 10-year period of the Bonneville contract.

Other miscellaneous revenues grew from $10.8 million in 2001 to $13.0 million in 2002, an increase of $2.2 million. Penalties and interest on overdue accounts generated $2.0 million more in revenue in 2002 than in the prior year, revenues from damages increased $0.9 million, and revenues from other operations increased $0.8 million. Net revenue from nonutility operations declined from $2.1 million in 2001 to $0.8 million in 2002.

OPERATING EXPENSES

Operating expenses declined from $657.7 million in 2001 to $650.6 million in 2002, a reduction of $7.1 million. Expenses in 2001 reflect the deferral of $300 million in power costs from 2001 to subsequent years; in 2002 expenses include the amortization of $100 million of these deferred charges. If the deferral of power costs in 2001 and their amortization in 2002 were excluded from consideration, operating expenses in 2002 would have been $407.1 million lower than in 2001.

Power and Transmission Costs—Power and transmission expenses in 2002 totalled $408.9 million, a decrease of $20.1 million from the 2001 level of $429.0 million.

Long-term purchased power expenses in 2002 were $223.7 million, $72.5 million higher than in the prior year, reflecting the full annual cost of additional contract resources acquired in 2001. The cost of power purchased under the new 10-year contract with Bonneville, which took effect on October 1, 2001, increased from $66.8 million in 2001, to $134.8 million. The amount of power delivered increased sharply under the terms of the new contract, from 2,384,896 MWh in 2001 to 4,158,297 MWh in 2002. The cost per unit of power also increased as Bonneville invoked its authority to increase rates under the contract's Cost Recovery

Adjustment Clause ("CRAC"). Bonneville used the CRAC to increase rates by as much as 46% over the period from October 1, 2001, through December 31, 2002. The Department's contract for power from the Klamath Falls Cogeneration Project provided 709,520 MWh of power in 2002 at a cost of $39.7 million. In 2001, 326,104 MWh of power were delivered at a cost of $18.5 million in the period following the July 1, 2001, effective date of the contract. Deliveries of power from the State Line Wind Project began in January 2002. The Department received 106,493 MWh of power from the project in 2002 at a cost of $8.9 million. Energy delivered to the Department under exchange agreements, computed using the blended weighted-average cost of power, declined by $22.1 million, from $28.0 million in 2001 to $5.9 million in 2002, reflecting both the lower volume and the lower unit value of exchanged energy. The cost of power purchased from the Lucky Peak Project fell from $16.0 million in 2001 to $12.4 million in 2002 as a result of the refinancing of the Lucky Peak Project's outstanding bonds in June 2002. The cost of power under the Department's contract with the Grand Coulee Project Hydroelectric Authority was $7.3 million in 2002, a reduction of $1.2 million from the 2001 level.

In 2001, the Department expended $518.8 million for purchases of power in the wholesale market to meet its obligations to serve load. Of this amount, $300.0 million was deferred to future years, leaving $218.8 million to be recorded as an expense in 2001. The amount of energy purchased in 2001 was unusually high because the Department's dependence on market purchases through September 30, 2001, was aggravated by drought conditions in the Northwest region, which drastically reduced the amount of generation at the Department's hydroelectric facilities. Extremely high prices in Western wholesale markets through May 2001 drove the cost of these market purchases to unprecedented levels. In late 2001, water conditions and market prices in the Northwest returned to more normal levels. In addition, energy from the contract resources that became available in 2001, coupled with the decline in system load in 2001, ensured that the Department would have sufficient power available to meet demand even under adverse water conditions. As a result, in 2002 the amount of power purchased in the wholesale market declined from 2,411,210 MWh to 898,613 MWh. The average price of these purchases declined from $215.15 per MWh in 2001 to $25.77 per MWh in 2002. The cost of short-term wholesale power purchases in 2002 was $23.2 million. The amortization of power costs deferred from 2001 added $100.0 million to this figure. Given the recognition of both the deferral of 2001 power costs and their amortization in 2002, the cost of short-term purchases shows a decline from $218.8 million in 2001 to $123.2 million in 2002, a reduction of $95.6 million. If power costs had not been deferred and amortized, the decline would have been $495.6 million.

The costs of operating and maintaining the Department's hydroelectric generating plants increased from $17.0 million in 2001 to $18.5 million in 2002, an increase of 9.0%. An increase of $1.4 million in fees paid to the Federal Energy Regulatory Commission ("FERC") accounts for most of the growth from 2001. In 2001, FERC charges were lower than normal due to the receipt of a credit of $0.8 million. Transmission costs, including both the cost of operating and maintaining the Department's own transmission lines and the cost of wheeling power over the lines of Bonneville and other utilities, increased from $25.8 million in 2001 to $35.4 million in 2002, an increase of $9.6 million or 36.9%. An October 1, 2001, increase in the transmission rates charged by Bonneville, the principal supplier of transmission services to the Department, accounts for most of this increase.

Other power-related expenses declined by $8.0 million from 2001 to 2002. In 2001, $4.1 million was paid to large industrial customers as incentives to reduce consumption; no such payments were made in 2002. The value of energy delivered to the Department through basis transactions declined from $4.4 million in 2001 to $1.3 million in 2002.

Other Operations and Maintenance Costs—Operations and maintenance costs, excluding the cost of power and transmission, increased from $114.6 million in 2001 to $115.0 in 2002, an increase of approximately 0.4%. Increases were experienced in energy management ($0.6 million) and administration and general activities ($0.3 million). The increase in conservation largely reflects the amortization of the Department's investment in energy management programs.

***Taxes and Other Intergovernmental Payments*—**Taxes and payments to local governments totalled $60.2 million in 2002, an increase of $7.6 million over the 2001 level. Revenue-based taxes paid to the City of Seattle and the state of Washington increased by $5.7 million, reflecting the increase in taxable revenue. Payments to suburban cities under the terms of franchise agreements with the Department increased from $1.6 million to $2.0 million. In 2001, tax payments were offset by a $1.2 million refund of arbitrage rebate payments made by the Department to the U.S. Treasury; there was no corresponding transaction in 2002.

***Depreciation*—**Depreciation expense increased from $61.5 million in 2001 to $66.5 million in 2002, an increase of $4.9 million. The increase reflects the impact of the Department's capital improvement program, which in recent years has focused on the replacement of aging plant and equipment and the expansion of capacity in the distribution system to meet customer demand.

NONOPERATING REVENUES AND EXPENSES

***Investment Income*—**Income from the investment of available cash balances totalled $10.1 million in 2002, a reduction of $3.2 million from the 2001 level. Declining cash balances and lower interest rates account for the decrease in interest income.

***Interest Expense*—**Debt-related expenses increased from $75.7 million in 2001 to $84.1 million in 2002, an increase of $8.4 million. An increase of $3.5 million in interest expense on first-lien bonds reflected the issuance of $503.7 million in revenue bonds and refunding bonds in March 2001, the issuance of $87.7 million in refunding bonds in December 2002, and the retirement of bonds at their maturity date in 2001 and 2002. Interest expense on second-lien, variable-rate bonds fell from $3.1 million in 2001 to $1.4 million in 2002 due to the decline in interest rates over that period. Interest expense for revenue anticipation notes issued by the Department in 2001 and 2002 was $2.5 million higher in 2002 than in the prior year. Interest on funds borrowed from the City's cash pool was $0.8 million higher than in 2002. The allowance for funds used during construction, which is a credit against interest expense, was $2.1 million lower in 2002 than in the prior year. The amortization of deferred charges related to outstanding debt increased by $0.9 million in 2002.

***Contributions, Grants and Transfers*—**Contributions in aid of construction fell from $12.5 million in 2001 to $10.6 million in 2001, reflecting the economic slowdown in the Seattle area. Grants and transfers decreased from $2.8 million in 2001 to $2.3 million in 2002. Operating transfers in 2001 included $0.9 million in funding from the Seattle General Fund for certain low-income and energy efficiency programs; there was no such transfer in 2002. Operating grants fell from $1.9 million in 2001 to $0.7 million in 2002. Offsetting these declines, the Department recorded $1.6 million in donated capital in 2002. There was no such donated capital in 2001.

FINANCIAL POSITION

Significant capital assets and related long-term debt as of December 31:

	2002	2001
SIGNIFICANT CAPITAL ASSETS:		
Utility plant—at original cost:		
Hydraulic	$ 527,022,003	$ 522,835,388
Capacity rights—3rd AC Intertie	34,298,665	34,298,665
Transmission	105,652,942	103,141,612
Distribution	1,068,429,863	1,016,151,812
General plant	297,080,942	278,415,352
	2,032,484,415	1,954,842,829
Less accumulated depreciation	(862,964,940)	(808,183,648)
	1,169,519,475	1,146,659,181
Construction work-in-progress	135,358,152	115,321,307
Nonoperating property—net of accumulated depreciation	7,703,571	7,216,228
Land and land rights	32,854,384	30,838,923
	1,345,435,582	1,300,035,639
Parity bond proceeds	66,663,074	166,131,625
	$1,412,098,656	$1,466,167,264
SIGNIFICANT LONG-TERM DEBT RELATED TO CAPITAL ASSETS:		
Revenue bonds	$1,244,693,325	$1,291,186,426
Bond premium—net	15,374,411	10,983,710
Less deferred charges on advanced refunding	(40,250,704)	(40,215,201)
	$1,219,817,032	$1,261,954,935
INVESTED IN CAPITAL ASSETS—NET OF RELATED DEBT	$ 192,281,624	$ 204,212,329

CONDENSED BALANCE SHEETS

	December 31, 2002	December 31, 2001
Assets:		
Utility plant	$ 1,345,435,582	$ 1,300,035,639
Capitalized purchased power commitment	50,279,621	56,947,942
Restricted assets	240,881,958	243,432,809
Current assets	190,990,153	155,835,416
Other assets	377,433,352	454,709,681
Total assets	$ 2,205,020,666	$ 2,210,961,487
Liabilities:		
Long-term debt	$ 1,365,447,879	$ 1,683,202,477
Noncurrent liabilities	67,994,521	63,771,698
Current liabilities	452,101,465	143,606,465
Deferred credits	21,216,712	20,255,473
Total liabilities	1,906,760,577	1,910,836,113
Equity:		
Invested in capital assets—net of related debt	192,281,624	204,212,329
Restricted:		
Deferred power costs	200,000,000	300,000,000
Other	66,229,640	35,746,815
Unrestricted	(160,251,175)	(239,833,770)
	298,260,089	300,125,374
Total liabilities and equity	$ 2,205,020,666	$ 2,210,961,487

UTILITY PLANT

Utility plant at original cost increased $77.6 million. The distribution system increased $52.3 million primarily for data processing-related underground conductors, devices, and conduits ($22.1 million); overhead, underground, and network underground services ($6.6 million); and poles, towers, and fixtures ($6.2 million).

General plant increased $18.7 million mostly for structures and improvements at the Department's North Service Center ($7.4 million), communications equipment ($4.9 million), and automated mapping ($2.9 million).

Hydroelectric facilities increased $4.2 million, primarily for rehabilitation work on water wheels and turbines ($2.3 million) and wildlife and mitigation ($1.5 million) at the Boundary Project, located on the Pend Oreille River in northeast Washington State.

COST CAPITALIZATION POLICIES

Administration and General Costs ("A&G")—The Department allocates a portion of A&G costs to the Capital Improvement and Conservation Program ("CICP"). A pool of allocable A&G costs is identified and an A&G allocation rate is computed by dividing the projected level of costs in the A&G cost pool in the following year by the projected number of non-A&G direct labor hours. Actual CICP labor hours are multiplied by the A&G allocation rate and included as a component of a CICP project. A&G costs capitalized were $19.4 million and $18.6 million in 2002 and 2001 respectively.

***Data Processing Systems*—**Systems development costs related to major new data processing applications are capitalized.

***High Ross*—**In setting rates for the 2000 – 2003 period, the City of Seattle Council decided to defer the capital portion of the remaining payments to B. C. Hydro under the High Ross agreement over the period through 2035. Previously, the entire amount of the $21.8 million annual payment was expensed. The deferred portion of the High Ross payments is treated as a component of capital requirements.

***Capitalization Limit*—**The Department of Executive Administration ("DEA") revised the capitalization limit for the City of Seattle from $1,000 to $5,000 effective for 2002. The effect of this change is an increase of approximately $2.0 million of charges, which were expensed in 2002 rather than capitalized.

SFAS NO. 71 ASSETS

Statement of Financial Accounting Standards ("SFAS") No. 71, *Accounting for the Effects of Certain Types of Regulations*, provides for the deferral of certain utility costs and related recognition in future years as the costs are recovered through future rates. Deferred costs are authorized by resolutions passed by the Seattle City Council.

	December 31, 2002	December 31, 2001
Deferred power costs	$200,000,000	$300,000,000
Capitalized energy management services—net	108,005,350	97,179,553
Capitalized relicensing costs	12,764,867	11,079,911
British Columbia—Ross Dam	31,448,059	22,574,618
Unrealized losses from fair valuations of		
Gas price swap		13,860,917
Short-term forward sales of electric energy	3,935,769	915,407
BPA Slice contract true-up payment	10,442,663	
Puget Sound Energy interconnection and substation	2,005,283	2,148,197
Skagit Environmental Endowment	2,115,225	2,232,737
Studies, surveys, and investigations	406,808	102,033
	$371,124,024	$450,093,373

Deferred assets totalled $371.1 million at December 31, 2002, decreasing $79.0 million from December 31, 2001. In 2001, $300.0 million of short-term wholesale power costs were deferred for recovery through future revenues. In 2002, $100.0 million of the deferred power costs were amortized; the balance of $200.0 million is expected to be recovered by the end of 2004.

In 2002, $10.4 million was deferred for the Bonneville Slice contract true-up billing. The Department is subject to true-up payments for the Department's fixed 4.6676 percentage of actual output and costs of Bonneville Slice power through October 1, 2011. Bonneville rate adjustments will be passed through to retail electric customers in the form of rate adjustments in accordance with the rates ordinance.

LONG-TERM DEBT

Activity during the year for long-term debt included issuance of $87.735 million in refunding revenue bonds to defease certain prior lien bonds. Scheduled redemption of certain prior lien bonds also took place in the normal course of business. See Note 3 of the accompanying financial statements.

After payment of cash operating expenses, net revenues available to pay debt service were equal to 2.51 times principal and interest on first-lien bonds. If, in addition, the amortization of $100 million in power costs deferred from 2001 is taken into account, net revenues would be equal to 1.61 times first-lien debt service.

ENVIRONMENTAL LIABILITIES

Environmental liabilities totalled $2.6 million at December 31, 2002, with no change from December 31, 2001. The majority of the liability is attributable to the estimated costs of cleaning up contaminated sediments in the lower Duwamish Waterway, which was designated a federal Superfund site by the Environmental Protection Agency in 2001. The Department is one of several responsible parties for this superfund site.

RISK MANAGEMENT

***Market Risk*—**The Department's exposure to market risk is managed by a Risk Management Committee. It is fundamentally risk averse, engaging in market transactions only to meet its load obligations or to lay off surplus energy. Except for strictly limited and closely monitored intra-day trading to take advantage of its hydro storage, the Department does not take market positions in anticipation of generating revenue.

With a significant portion of the Department's revenue expected from wholesale market sales, great emphasis is placed on the management of market risk. Processes, policies, and procedures designed to monitor and control these market risks, including credit risk, are in place, and engagement in the market is strictly governed by those policies. Formal segregation of the roles of the front, middle, and back offices ensures compliance.

The Department measures the market price risk in its portfolio on a weekly basis using a modified net revenue at risk measure that reflects not only price risk, but also the volumetric risk associated with its hydro-dominant power portfolio. Monte Carlo simulation is used to capture financial risk and scenario analysis for stress testing.

With a new portfolio in place since fall 2001, the Department is now long over 2 million MWh even in severe water conditions. This is in stark contrast to the energy crisis, when the Department was short 3.5 million MWh because of the drought. As a net seller in nearly every month of the year even during droughts, the Department's market risk is clearly very different.

The Department's approach to risk management has also changed. Prior to the energy crisis, operations were planned around average hydro conditions; now planning is performed around conditions close to drought until observed precipitation or snow pack surveys indicate otherwise.

While the Department's portfolio includes a gas turbine (a share of the Klamath Falls project), the Department's exposure to changes in the market price of gas is limited, as the Department has the right not to operate its share if the price of gas is too high relative to the price of electricity produced.

The Department mitigates credit risk by ensuring only qualifying counterparties are engaged in power marketing transactions in accordance with the Department's Credit Policy. A Credit Committee has been established to administer the Credit Policy. The Department performs initial credit evaluations for new counterparties and establishes credit limits based on approved criteria within the Credit Policy. Ongoing credit evaluations are performed and credit limits are updated regularly to reflect the current financial condition and credit worthiness of each counterparty.

***Self-Insurance*—**The Department is self-insured, including for terrorism, for casualty losses to its property, for environmental clean-up, and for certain losses arising from third-party claims. Expenses for injuries and damages are estimated and include citywide allocation of incurred but not reported claims.

CITY OF SEATTLE – CITY LIGHT DEPARTMENT

BALANCE SHEETS
DECEMBER 31, 2002 AND 2001

ASSETS	2002	2001
UTILITY PLANT—At original cost:		
Plant in service—excluding land	$ 2,032,484,415	$ 1,954,842,829
Less accumulated depreciation	(862,964,940)	(808,183,648)
	1,169,519,475	1,146,659,181
Construction work-in-progress	135,358,152	115,321,307
Nonoperating property—net of accumulated depreciation	7,703,571	7,216,228
Land and land rights	32,854,384	30,838,923
	1,345,435,582	1,300,035,639
CAPITALIZED PURCHASED POWER COMMITMENT	50,279,621	56,947,942
RESTRICTED ASSETS:		
Municipal Light & Power Bond Reserve Account:		
Cash and equity in pooled investments	77,975,000	70,993,458
Bond proceeds and other:		
Cash and equity in pooled investments	158,267,512	63,559,476
Investments		102,274,374
Special deposits and other	4,639,446	6,605,501
	240,881,958	243,432,809
CURRENT ASSETS:		
Cash and equity in pooled investments	34,694,513	3,759,018
Accounts receivable, net of allowance of $6,690,000 and $6,110,000	73,345,049	53,187,620
Unbilled revenues	60,079,107	61,366,163
Energy contracts	1,848,350	14,526,178
Materials and supplies at average cost	20,447,710	21,810,750
Prepayments, interest receivable, and other	575,424	1,185,687
	190,990,153	155,835,416
OTHER ASSETS:		
Capitalized energy management services—net	108,005,350	97,179,553
Deferred power costs	200,000,000	300,000,000
Capitalized relicensing costs	12,764,867	11,079,911
Other deferred charges and assets—net	56,663,135	46,450,217
	377,433,352	454,709,681
TOTAL	$ 2,205,020,666	$ 2,210,961,487

See notes to financial statements.

LIABILITIES	2002	2001
LONG-TERM DEBT:		
Revenue bonds and anticipation notes	$ 1,429,186,000	$ 1,651,872,500
Plus bond premium—net	17,127,583	13,196,678
Less deferred charges on advanced refunding	(40,250,704)	(40,215,201)
Less revenue bonds—current portion	(40,615,000)	(41,651,500)
Note payable—City of Seattle		100,000,000
	1,365,447,879	1,683,202,477
NONCURRENT LIABILITIES:		
Accumulated provision for injuries and damages	7,895,490	6,125,305
Compensated absences	9,819,410	9,568,451
Long-term purchased power obligation	50,279,621	56,947,942
Less obligation—current portion		(8,870,000)
	67,994,521	63,771,698
CURRENT LIABILITIES:		
Accounts payable and other	71,842,294	51,006,948
Accrued payroll and related taxes	4,668,171	3,820,619
Compensated absences	846,948	642,345
Accrued interest	21,531,101	22,802,987
Revenue anticipation notes	307,210,000	
Long-term debt	40,615,000	41,651,500
Purchased power obligation		8,870,000
Energy contracts	5,387,951	14,812,066
	452,101,465	143,606,465
DEFERRED CREDITS	21,216,712	20,255,473
Total liabilities	1,906,760,577	1,910,836,113
COMMITMENTS AND CONTINGENCIES (Notes 3, 6, and 10)		
EQUITY:		
Invested in capital assets—net of related debt	192,281,624	204,212,329
Restricted:		
Deferred power costs	200,000,000	300,000,000
Other	66,229,640	35,746,815
Unrestricted	(160,251,175)	(239,833,770)
	298,260,089	300,125,374
TOTAL	$ 2,205,020,666	$ 2,210,961,487

CITY OF SEATTLE – CITY LIGHT DEPARTMENT

STATEMENTS OF REVENUES, EXPENSES, AND CHANGES IN EQUITY
YEARS ENDED DECEMBER 31, 2002 AND 2001

	2002	2001
OPERATING REVENUES:		
Retail power revenues	$ 562,432,218	$ 503,437,272
Short-term wholesale power revenues	112,795,762	73,899,346
Other power-related revenues	21,110,534	44,303,333
Other	12,991,925	10,814,019
	709,330,439	632,453,970
OPERATING EXPENSES:		
Long-term purchased power	223,668,647	151,213,357
Short-term wholesale power purchases	23,153,996	218,781,800
Amortization of deferred power costs	100,000,000	
Other power expenses	8,147,996	16,143,942
Generation	18,546,296	17,012,159
Transmission	35,352,620	25,820,801
Distribution	37,649,578	38,122,827
Customer service	27,566,006	27,539,641
Energy management	9,514,572	8,887,010
Administrative and general—net	40,315,379	40,030,657
City of Seattle occupation tax	33,913,510	30,648,911
Other taxes	26,260,379	21,916,749
Depreciation	66,485,780	61,538,960
	650,574,759	657,656,814
Net operating income (loss)	58,755,680	(25,202,844)
NONOPERATING REVENUES (EXPENSES):		
Investment income	10,110,004	13,275,220
Interest expense	(81,340,397)	(73,873,786)
Amortization of debt expense	(2,717,316)	(1,786,694)
Other income (expense)—net	357,968	(1,048,013)
	(73,589,741)	(63,433,273)
Net loss before fees, grants, and transfers	(14,834,061)	(88,636,117)
FEES, GRANTS, AND TRANSFERS:		
Capital contributions	10,631,017	12,489,627
Grants and transfers	2,337,759	2,806,083
	12,968,776	15,295,710
NET LOSS	(1,865,285)	(73,340,407)
EQUITY:		
Beginning of year	300,125,374	373,465,781
End of year	$ 298,260,089	$ 300,125,374

See notes to financial statements.

CITY OF SEATTLE – CITY LIGHT DEPARTMENT

STATEMENTS OF CASH FLOWS
YEARS ENDED DECEMBER 31, 2002 AND 2001

	2002	2001
OPERATING ACTIVITIES:		
Cash received from customers and counterparties	$ 692,482,007	$ 671,289,411
Cash paid to suppliers, employees, and counterparties	(394,011,051)	(931,423,126)
Taxes paid	(59,423,235)	(50,134,407)
Net cash provided by (used in) operating activities	239,047,721	(310,268,122)
NONCAPITAL FINANCING ACTIVITIES:		
Proceeds from RAN and City of Seattle note	125,922,862	284,999,427
Principal paid on City of Seattle note	(100,000,000)	
Interest paid on RAN and City of Seattle note	(11,451,300)	(4,223,087)
Grant revenues received	1,289,390	1,014,343
Operating transfers received from the City of Seattle		315,000
Net cash provided by noncapital financing activities	15,760,952	282,105,683
CAPITAL AND RELATED FINANCING ACTIVITIES:		
Proceeds from long-term debt—net	88,247,757	513,343,978
Bond issue costs paid	(585,657)	(2,095,805)
Principal paid on long-term debt	(128,211,500)	(138,030,000)
Interest paid on long-term debt	(74,984,816)	(65,539,492)
Acquisition and construction of capital assets	(133,586,924)	(149,335,107)
Proceeds from sale of other capital assets	763,624	476,683
Capital fees	11,578,573	12,394,505
Net cash (used in) provided by capital and related financing activities	(236,778,943)	171,214,762
INVESTING ACTIVITIES:		
Proceeds from long-term loans receivable	137,933	250,441
Long-term loans issued	(8,137)	(116,765)
Proceeds from sale of investments	216,780,918	567,239,517
Purchases of investments	(114,511,442)	(656,263,060)
Interest received on investments	10,230,016	11,280,508
Net cash provided by (used in) investing activities	112,629,288	(77,609,359)
NET INCREASE IN CASH AND EQUITY IN POOLED INVESTMENTS	130,659,018	65,442,964
CASH AND EQUITY IN POOLED INVESTMENTS:		
Beginning of year	144,917,453	79,474,489
End of year	$ 275,576,471	$ 144,917,453

(Continued)

CITY OF SEATTLE – CITY LIGHT DEPARTMENT

STATEMENTS OF CASH FLOWS
YEARS ENDED DECEMBER 31, 2002 AND 2001

	2002	2001
RECONCILIATION OF NET OPERATING INCOME (LOSS) TO NET CASH PROVIDED BY (USED IN) OPERATING ACTIVITIES:		
Net operating income (loss)	$ 58,755,680	$ (25,202,844)
Adjustments to reconcile net operating income (loss) to net cash provided by (used in) operating activities:		
Depreciation and amortization	76,288,439	70,412,288
Amortization of deferred power costs	100,000,000	
Cash (used in) provided by changes in operating assets and liabilities:		
Accounts receivable	(15,586,755)	30,981,472
Unbilled revenues	1,287,056	(25,928,733)
Materials and supplies	3,895,411	315,615
Prepayments, interest receivable, and other	(571,654)	10,087,199
Capitalized relicensing and other deferred	12,210,283	(316,162,037)
Provision for injuries and damages	1,770,185	(327,102)
Accounts payable, accrued payroll, and other	6,800,764	(65,068,412)
Compensated absences	13,006	761,547
Energy contracts and deferred credits	(5,814,694)	9,862,885
Net cash provided by (used in) operating activities	$ 239,047,721	$ (310,268,122)
CASH AND EQUITY IN POOLED INVESTMENTS AT DECEMBER 31 CONSISTS OF:		
Cash and cash equivalents	$ 92,215,085	$ 13,653,054
Equity in pooled investments	183,361,386	131,264,399
	$ 275,576,471	$ 144,917,453
SCHEDULE OF NONCASH ACTIVITIES:		
Fair value adjustments of long-term investments	$ –	$ 4,897
In-kind capital contributions	$ 1,566,788	$ –

See notes to financial statements. (Concluded)

NOTE 1. OPERATIONS AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The City Light Department (the "Department") is the public electric utility of the City of Seattle (the "City"). The Department owns and operates certain generating, transmission, and distribution facilities and supplies electricity to approximately 360,600 customers. The Department supplies electrical energy to other City agencies at rates prescribed by City ordinances. The establishment of the Department's rates is within the exclusive jurisdiction of the City of Seattle Council. A requirement of Washington State law provides that rates must be fair, nondiscriminatory, and fixed to produce revenue adequate to pay for operation and maintenance expenses and to meet all debt service requirements payable from such revenue. The Department pays occupation taxes to the City based on total revenues.

The Department also provides nonenergy services to other City funds and received $2.3 million in 2002 and $5.8 million in 2001 for such services. Included in accounts receivable at December 31, 2002 and 2001, are $2.6 million and $1.1 million, respectively, representing amounts due from other City funds for services provided, reimbursements, and interest receivable on cash and equity in pooled investments.

The Department receives certain services from other City funds and paid approximately $37.9 million and $35.2 million, respectively, in 2002 and 2001 for such services. Included in accounts payable for the same time periods are $6.6 million and $4.5 million, respectively, representing amounts due other City funds for goods and services received.

Accounting Standards—The accounting and reporting policies of the Department are regulated by the Washington State Auditor's Office, Division of Municipal Corporations, and are based on the Uniform System of Accounts prescribed for public utilities and licensees by the Federal Energy Regulatory Commission ("FERC"). The financial statements are also prepared in conformity with accounting principles generally accepted in the United States of America as applied to governmental units. The Governmental Accounting Standards Board ("GASB") is the accepted standard-setting body for establishing governmental accounting and financial reporting principles. The Department has applied all applicable GASB pronouncements as well as the following pronouncements, except for those that conflict with or contradict GASB pronouncements: Statements and Interpretations of the Financial Accounting Standards Board ("FASB"), Accounting Principles Board Opinions, and Accounting Research Bulletins of the Committee on Accounting Procedures. The more significant of the Department's accounting policies are described below.

In June 1999, GASB issued GASB Statement No. 34, *Basic Financial Statements—and Management's Discussion and Analysis—for State and Local Governments*, adopted by the Department in 2002 with the following amendments: GASB Statement No. 37, *Basic Financial Statements—and Management's Discussion and Analysis—for State and Local Governments: Omnibus—an Amendment of GASB Statements No. 21 and No. 34,* and GASB Statement No. 38, *Certain Financial Statement Note Disclosures*. GASB Statement No. 34, as amended, and GASB Statement No. 38 establish specific standards for external financial reporting for state and local governments. As a result of adopting these statements, the basic financial statement presentation was significantly changed, including adding management's discussion and analysis of operating, investing, and financing activities. GASB

Statement No. 34 also requires the classification of fund equity into three components – invested in capital assets, net of related debt; restricted; and unrestricted, defined as follows:

- *Invested in capital assets, net of related debt* consists of capital assets, net of accumulated depreciation reduced by the net outstanding debt balances.

- *Restricted net assets* has constraints placed on use, either externally or internally. Constraints include those imposed by creditors (such as through debt covenants), grants, or laws and regulations of other governments, or by law through constitutional provisions or enabling legislation or by the Seattle City Council.

- *Unrestricted net assets (deficit)* consists of assets and liabilities that do not meet the definition of "restricted net assets" or "invested in capital assets, net of related debt."

Under GASB Statement No. 34, the statement of operations and changes in retained earnings was renamed the statement of revenues, expenses, and changes in equity.

In June 2001, the FASB issued Statement of Financial Accounting Standards ("SFAS") No. 143*, Accounting for Asset Retirement Obligations*. The objective of the statement is to address financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. The statement is effective for the Department in 2003, and the Department is in the process of evaluating the financial impact of the statement.

In August 2001, the FASB issued SFAS No. 144*, Accounting for the Impairment or Disposal of Long-Lived Assets*, which supercedes SFAS No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of.* SFAS No. 144 retains the basic provisions of SFAS No. 121 for the measurement and recognition of the impairment of long-lived assets to be held and used, as well as the measurement of long-lived assets to be disposed of by sale. SFAS No. 144 resolves significant implementation issues related to SFAS No. 121 and retains the amendments in SFAS No. 121 pertaining to regulatory assets under SFAS No. 71 and SFAS No. 90, *Regulated Enterprises—Accounting for Abandonments and Disallowances of Plant Costs*. SFAS No. 144 is effective for fiscal years beginning after December 15, 2001, and was adopted by the Department in 2002 without an impact to financial position or operations.

In April 2002, the FASB issued SFAS No. 145, *Recission of FASB Statements Nos. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections.* SFAS No. 145 rescinds various pronouncements regarding early extinguishment of debt and allows extraordinary accounting treatment for early extinguishment only when the provisions of Accounting Principles Board Opinion No. 30, *Reporting the Results of Operations, Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions* have been met. SFAS No. 145 provisions regarding early extinguishment of debt are generally effective for the Department for advance refundings using cash and are effective for the Department in 2003. For advance refundings made by issuance of new bonds, the transactions are accounted for in accordance with GASB Statement No. 7, *Advance Refundings Resulting in Defeasance of Debt* and GASB Statement No. 23, *Accounting and Financial Reporting for Refundings of Debt Reported by Proprietary Activities.* The Department does not anticipate a material impact on financial position or operations as a result of adopting SFAS No. 145.

Nonexchange Transactions—In December 1998, GASB issued GASB Statement No. 33*, Accounting and Financial Reporting for Nonexchange Transactions*, which requires reporting nonexchange transactions as revenues effective for periods beginning after June 15, 2000. Capital fees from private sources were reported as a component of equity as contributions in aid of construction prior to implementation of GASB Statement No. 33. Capital fees, grants, and transfers in the amount of $13.0 million and $15.3 million are reported for 2002 and 2001 on the statements of revenues, expenses, and changes in equity as nonoperating revenues as a result of the adoption of this statement.

***Derivative Instruments*—**In June 1998, FASB issued SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* This statement was amended in June 2000 by SFAS No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities.* Both statements are effective for fiscal years beginning after June 15, 2000, and were adopted by the Department in 2001. SFAS Nos. 133 and 138 require that the fair value of derivative financial instruments be recognized as either assets or liabilities on the Department's balance sheet and that changes in the fair value of a derivative instrument be included in earnings. The Department has outstanding sales and purchases of electric energy under short-term forward contracts for electricity that meet the definition of a derivative in accordance with SFAS No. 133. In addition, the Department entered into a fixed for variable natural gas price swap in April 2001 to fix the fuel expense for the Klamath Falls Cogeneration Project from July 2001 through December 2002 and recognized $12.3 million and $6.9 million in 2002 and 2001, respectively, for swap settlements that are reported in long-term purchased power expenses. Derivative values by balance sheet caption as of December 31 are as follows:

	2002	**2001**
Current assets:		
Energy contracts:		
Forward energy sales	$ 1,452,182	$ 14,526,178
Forward energy purchases	396,168	
	1,848,350	14,526,178
Other assets:		
Other deferred charges—net:		
Unrealized losses from fair valuation of:		
Gas price swap		13,860,917
Forward energy sales	3,935,769	
Forward energy purchases		915,407
	$ 5,784,119	$ 29,302,502
Current liabilities:		
Gas price swap	$ –	$ 13,860,917
Forward energy sales	5,387,951	35,742
Forward energy purchases		915,407
	5,387,951	14,812,066
Deferred credits:		
Unrealized gains from fair valuation of:		
Forward energy sales		14,490,436
Forward energy purchases	396,168	
	$ 5,784,119	$ 29,302,502

In accordance with Seattle City Council Resolution 30290, deferred losses are regulatory assets, and deferred gains are regulatory liabilities, pursuant to SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*. Thus, SFAS Nos. 133 and 138 have no current year impact on recorded earnings.

The Department's conclusions regarding the accounting treatment and financial statement effect of SFAS No. 133 could change based on interpretations of issues pending before the FASB.

Utility Plant**—**Utility plant is recorded at original cost, which includes both direct costs of construction or acquisition and indirect costs, including an allowance for funds used during construction. The allowance represents the estimated costs of financing construction projects and is computed using the Department's long-term borrowing rate. The allowance totalled $3.6 million and $5.7 million in 2002 and 2001, respectively, and is reflected as a reduction of interest expense in the statements of revenues, expenses, and changes in equity. Property constructed with capital fees received from customers is included in utility plant. Capital fees totalled $10.6 million in 2002 and $12.5 million in 2001. Provision for depreciation is made using the straight-line method based upon estimated economic lives, which range from three to 50 years, of related operating assets. The Department uses a half-year convention method on the assumption that additions and replacements are placed in service at mid-year. The composite depreciation rate was approximately 3.3% in 2002 and 3.2% in 2001. When operating plant assets are retired, their original cost together with removal costs, less salvage, is charged to accumulated depreciation. The cost of maintenance and repairs is charged to expense as incurred, while the cost of replacements and betterments is capitalized.

Utility plant in service at original cost, excluding land, at December 31, 2002, consists of:

	Hydraulic Production	Transmission	Distribution	General	Total
Beginning balance	$ 522,835,388	$ 137,440,277	$ 1,016,151,812	$ 278,415,352	$ 1,954,842,829
Capital acquisitions	5,824,060	3,332,380	57,041,644	22,452,494	88,650,578
Dispositions	(1,637,445)	(821,049)	(3,534,867)	(3,786,905)	(9,780,266)
Transfers and adjustments			(1,228,726)		(1,228,726)
	527,022,003	139,951,608	1,068,429,863	297,080,941	2,032,484,415
Less accumulated depreciation	(275,296,702)	(60,272,213)	(383,433,656)	(143,962,369)	(862,964,940)
Ending balance	$ 251,725,301	$ 79,679,395	$ 684,996,207	$ 153,118,572	$ 1,169,519,475

FERC licenses for owned hydraulic production facilities consist of:

Project	License Issued	License Effective	License Expires	Years Licensed
Boundary	07/10/1960	10/01/1960	10/01/2010	50
Gorge	05/16/1995	05/01/1995	05/01/2025	30
Diablo	05/16/1995	05/01/1995	05/01/2025	30
Ross	05/16/1995	05/01/1995	05/01/2025	30
Newhalem	02/07/1997	02/01/1997	02/01/2027	30
South Fork Tolt	03/29/1984	03/01/1984	03/01/2024	40

Restricted Assets**—**In accordance with the Department's bond resolutions, state law, or other agreements, separate restricted assets have been established. These assets are restricted for specific purposes, including the establishment of the Municipal Light & Power ("ML&P") Bond Reserve Account, financing of the Department's ongoing Capital Improvement Program, and other purposes.

***Accounts Receivable*—**Accounts receivable at December 31 consists of:

	2002	2001
Retail power	$ 57,304,001	$ 42,520,721
Allowance for doubtful accounts	(4,000,000)	(3,500,000)
	53,304,001	39,020,721
Wholesale power	13,950,626	6,538,072
Allowance for doubtful accounts	(1,520,000)	(1,520,000)
	12,430,626	5,018,072
Fees, grants, and other	4,693,499	6,704,916
Allowance for doubtful accounts	(1,170,000)	(1,090,000)
	3,523,499	5,614,916
Interfund	2,626,871	1,100,652
Due from other governments	1,460,052	2,433,259
	$ 73,345,049	$ 53,187,620

***Compensated Absences*—**Permanent employees of the Department earn vacation time in accordance with length of service. A maximum of 480 hours may be accumulated and, upon termination, employees are entitled to compensation for unused vacation. At retirement, employees receive compensation equivalent to 25% of their accumulated sick leave. The Department accrues all costs associated with compensated absences, including payroll taxes.

***Accounts Payable and Other*—**The composition of accounts payable and other at December 31, is as follows:

	2002	2001
Vouchers payable	$ 10,090,145	$ 8,544,835
Power accounts payable	40,354,341	25,263,010
Interfund payable	6,566,460	4,527,245
Taxes payable	8,541,055	8,396,449
Claims payable—current	2,580,752	1,965,511
Guarantee deposit and contract retainer	1,998,070	1,767,583
Other accounts payable	1,711,471	542,315
	$ 71,842,294	$ 51,006,948

***Revenue Recognition*—**Service rates are authorized by City ordinances. Billings are made to customers on a monthly or bimonthly basis. Revenues for energy delivered to customers between the last billing date and the end of the year are estimated and reflected in the accompanying financial statements under the caption unbilled revenues.

The Department's customer base comprises four identifiable groups, which accounted for electric energy sales as follows:

	2002	2001
Residential	37.6 %	37.3 %
Commercial	42.3	41.6
Industrial	11.2	12.3
Governmental	8.9	8.8
	100.0 %	100.0 %

Use of Estimates—The preparation of the financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect amounts reported in the financial statements. The Department used significant estimates in determining reported unbilled revenues, energy contract assets and liabilities, accumulated provision for injuries and damages, allowance for doubtful accounts, accrued sick leave, and other contingencies. Actual results may differ from those estimates.

Significant Risk and Uncertainty—The Department is subject to certain business risks that could have a material impact on future operations and financial performance. These risks include prices on the wholesale markets for short-term power transactions; interest rates; water conditions, weather, and natural disaster related disruptions; terrorism; collective bargaining labor disputes; fish and other Endangered Species Act ("ESA") issues; Environmental Protection Agency regulations; federal government regulations or orders concerning the operations, maintenance, and/or licensing of hydroelectric facilities; other governmental regulations; and the deregulation of the electrical utility industry.

Reclassifications—Certain 2001 account balances have been reclassified to conform to the 2002 presentation.

NOTE 2. CASH AND EQUITY IN POOLED INVESTMENTS AND INVESTMENTS

Cash and Equity in Pooled Investments and Investments—The City pools and invests all temporary cash surpluses for City departments. These residual investments may consist of deposits with qualified public depositories; obligations of the United States or its agencies or wholly owned corporations; obligations of eligible government-sponsored enterprises; and certain bankers' acceptances, commercial paper, general obligation bonds or warrants, repurchase agreements, reverse repurchase agreements, mortgage-backed securities, derivative-based securities, and participation in the State Treasurer's local government investment pool and are in accordance with the Revised Code of Washington 35.39.032 and 39.58. According to City policy, securities purchased will have a maximum maturity of no longer than 15 years, and the average maturity of all securities owned should be no longer than five years. Also by City policy, the City may operate a securities lending program, and there were transactions during 2002 and 2001. There were no securities lending program transactions outstanding at year end 2002 or 2001. The Department's equity in residual investments is reflected as cash and equity in pooled investments. The City's residual investment pool did not include reverse repurchase agreements at the end of 2002 or 2001; the City did not invest in such instruments during 2002 or 2001. Derivative-based securities were owned by the City pool during 2002 and 2001 and at both year ends. These securities were callable U.S. government agency instruments. Earnings and adjustments to fair value from the investment pool are prorated monthly to City departments based on the average daily cash balances of participating funds.

Banks or trust companies acting as the City's agents hold most of the City's investments in the City's name, with respect to credit risk as defined in GASB Statement No. 3, *Deposits with Financial*

Institutions, Investments (including Repurchase Agreements), and Reverse Repurchase Agreements. All transactions are executed with authorized security dealers, financial institutions, or securities lending agents on a delivery versus payment basis.

The first $100,000 of bank deposits are federally insured. The Washington State Public Deposit Protection Commission ("PDPC") collateralizes deposits in excess of $100,000. The PDPC is a multiple financial institution collateral pool. There is no provision for the PDPC to make additional pro rata assessments if needed to cover a loss. Therefore, the PDPC protection is of the nature of collateral, not of insurance.

Securities with maturities exceeding three months at time of purchase are reported at fair value on the balance sheets; the net increase (decrease) in the fair value of those investments is reported as part of investment income. At December 31, changes in the fair value of investments resulted in unrealized gains of $817,806 and $907,046 for 2002 and 2001, respectively.

The cash pool operates like a demand deposit account in that all City departments, including the Department, may deposit cash at any time and can also withdraw cash out of the pool without prior notice or penalty. Accordingly, the statements of cash flows reconcile to cash and equity in pooled investments.

Cash and cash equivalents included in cash and equity in pooled investments at December 31 consists of:

	2002	**2001**
Restricted assets:		
Municipal Light & Power Bond Reserve Account	$ 24,998,402	$ 3,609,215
Bond proceeds and other	51,152,110	3,236,017
Special deposits and other	4,639,446	6,605,501
	80,789,958	13,450,733
Current assets	11,425,127	202,321
	$ 92,215,085	$ 13,653,054

Equity in pooled investments and U.S. government securities are reported at fair values based on quoted market prices for those or similar securities and is as follows at December 31:

	2002	**2001**
Restricted assets:		
Municipal Light & Power Bond Reserve Account—		
Equity in pooled investments	$ 52,976,598	$ 67,384,243
Bond proceeds and other:		
Equity in pooled investments	107,115,402	60,323,459
Investments		102,274,374
	160,092,000	229,982,076
Current assets:		
Equity in pooled investments	23,269,386	3,556,697
	$183,361,386	$233,538,773

NOTE 3. LONG-TERM AND SHORT-TERM DEBT

At December 31, the Department's long-term and short-term debt consists of the following:

LONG-TERM				2002	2001
Prior Lien Bonds:					
2002	ML&P Refunding Revenue Bonds	3.000% to 4.500%	due 2014	$ 87,735,000	$ –
2001	ML&P Improvements and Refunding Revenue Bonds	5.000% to 5.500%	due 2026	503,700,000	503,700,000
2000	ML&P Revenue Bonds	4.500% to 5.625%	due 2025	98,830,000	98,830,000
1999	ML&P Revenue Bonds	5.000% to 6.000%	due 2024	158,000,000	158,000,000
1998B	ML&P Revenue Bonds	4.750% to 5.000%	due 2024	90,000,000	90,000,000
1998A	ML&P Refunding Revenue Bonds	4.500% to 5.000%	due 2020	102,835,000	103,515,000
1997	ML&P Revenue Bonds	5.000% to 5.125%	due 2022	30,000,000	30,000,000
1996	ML&P Revenue Bonds	5.250% to 5.625%	due 2021	29,135,000	30,000,000
1995B	ML&P Revenue Bonds	4.050% to 4.800%	due 2005	456,000	697,500
1995A	ML&P Revenue Bonds	5.000% to 5.700%	due 2020	55,815,000	56,665,000
1994	ML&P Revenue Bonds	6.00%	due 2004	6,280,000	9,385,000
1993	ML&P Revenue & Refunding Revenue Bonds	2.200% to 5.500%	due 2018	166,360,000	237,135,000
1992B	ML&P Revenue Bonds	2.750% to 5.750%	due 2010	–	48,335,000
				1,329,146,000	1,366,262,500
Subordinate Lien Bonds:					
1996	ML&P Adjustable Rate Revenue Bonds	variable	due 2021	19,140,000	19,800,000
1993	ML&P Adjustable Rate Revenue Bonds	variable	due 2018	18,700,000	19,600,000
1991B	ML&P Adjustable Rate Revenue Bonds	variable	due 2016	17,500,000	18,300,000
1991A	ML&P Adjustable Rate Revenue Bonds	variable	due 2016	25,000,000	25,000,000
1990	ML&P Adjustable Rate Revenue Bonds	variable	due 2015	19,700,000	20,700,000
				100,040,000	103,400,000
Revenue Anticipation Notes—					
2001 ML&P Revenue Anticipation Notes		4.500% and 5.250%	due 2003	–	182,210,000
City of Seattle Note Payable—2001 Note Payable		variable	due 2004	–	100,000,000
Total long-term debt				$ 1,429,186,000	$ 1,751,872,500

SHORT-TERM				2002	2001
Revenue Anticipation Notes:					
2001	ML&P Revenue Anticipation Notes	4.500% and 5.250%	due 2003	$ 182,210,000	$ –
2002	ML&P Revenue Anticipation Notes	2.500%	due 2003	125,000,000	–
Total short-term debt				$ 307,210,000	$ –

The Department had the following activity in long-term debt during 2002:

	Balance at December 31, 2001	Additions	Reductions	Balance at December 31, 2002	Current Portion
Prior Lien Bonds	$ 1,366,262,500	$ 87,735,000	$(124,851,500)	$ 1,329,146,000	$ 37,030,000
Subordinate Lien Bonds	103,400,000		(3,360,000)	100,040,000	3,585,000
Revenue Anticipation Notes	182,210,000		(182,210,000)		
Note payable—City of Seattle	100,000,000		(100,000,000)		
	$ 1,751,872,500	$ 87,735,000	$(410,421,500)	$ 1,429,186,000	$ 40,615,000

***Prior Lien Bonds*—**In December 2002, the Department issued $87.7 million in ML&P Refunding Revenue Bonds that bear interest at rates ranging from 3.00% to 4.50% and mature serially from December 1, 2003, through 2014. The arbitrage yield for the 2002 bonds is 3.427%. Arbitrage yield, when used in computing the present worth of all payments of principal and interest on the bonds, produces an amount equal to the issue price of the bonds. Proceeds were used to defease certain outstanding prior lien bonds. The debt service on the refunding bonds requires a cash flow of $110.4 million, including $22.7 million in interest. The difference between the cash flows required to service the old and the new debt and complete the refunding totalled $5.1 million, and the aggregate economic gain totalled $5.97 million at net present value. The loss on refunding was $8.9 million and is being amortized over the life of the new bonds. The unamortized balance of the loss on refunding at December 31, 2002, is $8.8 million.

In March 2001, the Department issued $503.7 million in ML&P Improvements and Refunding Revenue Bonds that bear interest at rates ranging from 5.00% to 5.50% and mature serially from March 1, 2004, through 2026. The arbitrage yield for the 2001 bonds is 4.99%. Proceeds were used to finance certain capital improvements and conservation programs and to defease certain outstanding prior lien bonds. As of the end of December 31, 2002 and 2001, respectively, $61.4 million and $161.7 million in proceeds remained from the 2001 bond issue that were and will continue to be used to fund the ongoing capital improvement and conservation program. The loss on refunding for the 2001 bonds was $9.4 million and is being amortized over the life of the new bonds. The unamortized balance of the loss on refunding at December 31, 2002 and 2001, was $8.6 million and $9.2 million, respectively.

The debt service on the 2001 refunding bonds requires a cash flow of $194.67 million, including $70.07 million in interest. The difference between the cash flows required to service the old and the new debt and complete the refunding totalled $(0.3) million, and the aggregate economic gain totalled $5.13 million at net present value.

Future debt service requirements for prior-lien bonds are as follows:

Year Ending December 31,	Principal Redemptions	Interest Requirements	Total
2003	$ 37,030,000	$ 69,338,346	$ 106,368,346
2004	48,100,000	67,340,816	115,440,816
2005	49,936,000	64,862,402	114,798,402
2006	53,480,000	62,460,798	115,940,798
2007	56,145,000	59,792,255	115,937,255
2008 – 2012	307,035,000	253,251,731	560,286,731
2013 – 2017	318,200,000	169,534,350	487,734,350
2018 – 2022	287,070,000	86,532,170	373,602,170
2023 – 2026	172,150,000	17,138,284	189,288,284
	$1,329,146,000	$ 850,251,152	$2,179,397,152

The Department is required by ordinance to fund reserves for prior lien bond issues in an amount equal to the lesser of (a) the maximum annual debt service on all bonds secured by the reserve account or (b) the maximum amount permitted by the Internal Revenue Code ("IRC") of 1986 as a reasonably required reserve or replacement fund. Upon issuance of the 2002 bonds, the maximum annual debt service on prior lien bonds remained at $115.9 million. The IRC's requirement increased from $105.6 million to $113.5. At December 31, 2002, the balance in the reserve account was $78.0 million at fair value. The reserve must be fully funded by December 1, 2007.

In addition to the 2002 refunding revenue bonds, the Department has previously issued several refunding revenue bonds for the purpose of defeasing certain outstanding prior lien bonds. Refunding revenue bonds were also issued in 2001, 1998, and 1993. Proceeds from the refunding bonds were placed in separate irrevocable trusts to provide for all future debt service payments on the bonds defeased. Accordingly, neither the assets of the respective trust accounts nor the liabilities for the defeased bonds are reflected in the Department's financial statements. The bonds defeased in 2002, 1998, and 1993 had outstanding principal balances of $86.6 million, $94.7 million, and $6.3 million as of December 31, 2002, respectively. Funds held in the respective trust accounts on December 31, 2002, are sufficient to service and redeem the defeased bonds.

***Subordinate Lien Bonds*—**The Department is authorized to issue a limited amount of adjustable rate revenue bonds, which are subordinate to prior lien bonds with respect to claim on revenues. Subordinate lien bonds may be issued to the extent that the new bonds will not cause the aggregate principal amount of such bonds then outstanding to exceed the greater of $70 million or 15% of the aggregate principal amount of prior lien bonds then outstanding. Subordinate bonds may be remarketed daily, weekly, short-term, or long-term and may be converted to prior lien bonds when certain conditions are met.

In December 1996, the Department issued ML&P Adjustable Rate Revenue Bonds in the amount of $19.8 million, subject to a mandatory redemption schedule spanning the period from June 1, 2002, to June 1, 2021. The bonds had an outstanding balance of $19.1 million at December 31, 2002. These bonds were marketed weekly at an interest rate ranging from 1.00% to 1.80% during 2002. Proceeds were used to finance a portion of the capital improvement and conservation program.

The 1990 bonds and 1991 Series B bonds were marketed on a short-term basis during 2002, with interest rates ranging from 1.10% to 2.65%. The 1990 bonds and the 1991 Series B bonds had an outstanding balance of $19.7 million and $17.5 million, respectively, at December 31, 2002.

The 1991 Series A bonds and the 1993 bonds were priced weekly at interest rates from 0.88% to 1.80% in 2002. The 1991 Series A bonds and the 1993 bonds had an outstanding balance of $25.0 million and $18.7 million, respectively, at December 31, 2002.

Future debt service requirements on these bonds, based on actual interest rates in effect as of December 31, 2002, ranging from 1.20% to 1.51% through year 2021, are as follows:

Year Ending December 31,	Principal Redemptions	Interest Requirements	Total
2003	$ 3,585,000	$ 1,571,284	$ 5,156,284
2004	4,115,000	1,336,089	5,451,089
2005	4,445,000	1,294,522	5,739,522
2006	4,775,000	1,216,303	5,991,303
2007	5,305,000	1,149,689	6,454,689
2008 - 2012	33,945,000	4,511,193	38,456,193
2013 - 2017	37,055,000	1,740,723	38,795,723
2018 - 2021	6,815,000	178,431	6,993,431
	$ 100,040,000	$ 12,998,234	$ 113,038,234

Revenue Anticipation Notes**—**In November 2002, the Department issued $125.0 million in ML&P Revenue Anticipation Notes (“RANs”) at an interest rate of 2.50% with an arbitrage yield of 1.49%. The 2002 RANs mature in November 2003.

In March 2001, the Department issued $182.2 million in ML&P RANs. $136.7 million of the 2001 RANs bear interest at a rate of 4.50%, and $45.5 million bear interest at a rate of 5.25%. The arbitrage yield of the 2001 RANs is 3.75%. The 2001 RANs mature in March 2003.

All RANs are special limited obligations of the Department payable from and secured by gross revenues. Proceeds were used to finance operating expenses for each respective year. The RANs are on a lien subordinate to prior lien bonds and subordinate lien bonds; there is no reserve account securing repayment, and there is no debt service coverage requirement. Debt service requirements for the RANs are as follows:

Year Ending December 31,	Principal Redemptions	Interest Requirements	Total
2003	$ 307,210,000	$ 7,324,362	$ 314,534,362

***Fair Value*—**The fair value of the Department's bonds and RANs is estimated based on the quoted market prices for the same or similar issues or on the current rates offered to the Department for debt of the same remaining maturities. Carrying amounts and fair values are as follows at December 31:

	2002		2001	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt:				
Prior lien bonds	$1,344,779,509	$1,407,056,096	$1,377,523,172	$1,385,989,653
Subordinate lien bonds	99,780,904	100,040,000	103,123,038	103,400,000
RANs	308,963,171	309,942,021	184,422,967	186,594,405
	$1,753,523,584	$1,817,038,117	$1,665,069,177	$1,675,984,058

***Amortization*—**Bond issue costs, discounts, and premiums are amortized using the effective interest method over the term of the bonds.

The excess of costs incurred over the carrying value of bonds refunded on early extinguishment of debt is amortized as a component of interest expense using both the straight-line and bonds-outstanding methods over the terms of the issues to which they pertain. Deferred refunding costs amortized to interest expense totalled $4.2 million in 2002 and $2.1 million in 2001. Deferred refunding costs in the amount of $40.3 million and $40.2 million are reported as a component of long-term debt in the 2002 and 2001 balance sheets, respectively.

***Note Payable*—**In late December 2001, the City authorized an interfund loan (note payable) to the Department from the City's Consolidated (Residual) Cash Portfolio in an amount up to $110.0 million, of which $100.0 million was outstanding as of December 31, 2001. The purpose of the note payable was for working capital and was due on or before March 31, 2003. The loan was repaid on January 1, 2002, and was carried as a negative operating cash balance during part of 2002. The loan was repaid as of December 31, 2002, and may be carried as a negative operating cash balance in 2003 until maturity. The interest rate for the note payable was equal to the rate of return earned by the City's Consolidated (Residual) Cash Portfolio in 2002 or 4.238%.

NOTE 4. SEATTLE CITY EMPLOYEES' RETIREMENT SYSTEM

The Seattle City Employees' Retirement System ("SCERS") is a single-employer defined benefit, public employee retirement system, covering employees of the City and administered in accordance with Chapter 41.28 of the Revised Code of Washington and Chapter 4.36 of the Seattle Municipal Code. SCERS is a pension trust fund of the City.

All employees of the City are eligible for membership in SCERS with the exception of uniformed police and fire personnel who are covered under a retirement system administered by the state of Washington. Employees of Metro ("King County") and the King County Health Department who established membership in SCERS when these organizations were City departments were allowed to continue their SCERS membership. As of the actuarial valuation date, there were 4,858 annuitants receiving benefits and 8,353 active members of SCERS. In addition, 1,199 vested terminated employees were entitled to future benefits, and 185 terminated employees had restored their contributions due to the provisions of the portability statutes and may be eligible for future benefits.

SCERS provides retirement, death, and disability benefits. Retirement benefits vest after five years of credited service, while death and disability benefits vest after 10 years of service. Retirement benefits are calculated as 2% multiplied by years of creditable service, multiplied by average salary, based on the highest 24 consecutive months, excluding overtime. The benefit is actuarially reduced for early retirement.

Actuarially recommended contribution rates both for members and for the employer were 8.03% of covered payroll during 2002 and 2001.

Under the authority of the state and City, SCERS operates a securities lending program, and there were transactions during 2002 and 2001. SCERS has had no losses resulting from a default, and SCERS did not have negative credit exposure at December 31, 2002 or December 31, 2001.

SCERS issues stand-alone financial statements that may be obtained by writing to the Seattle City Employees' Retirement System, 801 Third Avenue, Suite 300, Seattle, Washington 98104; telephone: (206) 386-1292.

Employer contributions for the City were $36.6 million and $32.7 million in 2002 and 2001, respectively, and the annual required contributions were made in full. The recent performance of the stock market has increased the Unfunded Actuarial Accrued Liabilities ("UAAL") of SCERS. It is not known whether employer contributions will be necessary in the foreseeable future to fund a portion of SCERS's UAAL.

Actuarial data

Valuation date	January 1, 2002
Actuarial cost method	Entry age
Amortization method	Level percent
Remaining amortization period	33.7 years
Amortization period	Open
Asset valuation method	Fair market value

Actuarial assumptions*	**Percentage**
Investment rate of return	8.00%
Projected general wage increases	4.50
Cost-of-living year-end bonus dividend	0.67

* Underlying price inflation at 4.0%.

Schedule of funding progress for the City (dollar amounts in millions):

Actuarial Valuation Date January 1,	Actuarial Value of Assets (a)	Actuarial Accrued Liabilities ("AAL") Entry Age (1) (b)	Unfunded AAL ("UAAL") (2) (b-a)	Funding Ratio (a/b)	Covered Payroll (3) (c)	UAAL or Excess as a Percentage of Covered Payroll ((b-a)/c)
2000	$ 1,582.7	$ 1,403.1	$ (179.6)	112.8 %	$ 370.4	(48.5)%
2001(4)	1,493.1	1,490.3	(2.8)	100.2	405.0	(.7)
2002	1,383.7	1,581.4	197.7	87.5	405.1	48.8

(1) Actuarial present value of benefits less actuarial present value of future normal costs based on entry age actuarial cost method.
(2) Actuarial accrued liabilities less actuarial value of assets; funding excess if negative.

(3) Covered payroll includes compensation paid to all active employees on which contributions are calculated.
(4) Information for January 1, 2001, was provided by an actuarial study, rather than a full valuation.

NOTE 5. DEFERRED COMPENSATION

The Department's employees may contribute to the City's Voluntary Deferred Compensation Plan (the "Plan"). The Plan, available to City employees and officers, permits participants to defer a portion of their salary until future years. The deferred compensation is paid to participants and their beneficiaries upon termination, retirement, death, or unforeseeable emergency.

Effective January 1, 1999, the Plan became an eligible deferred compensation plan under Section 457 of the IRC of 1986, as amended, and a trust exempt from tax under IRC Sections 457(g) and 501(a). The Plan is operated for the exclusive benefit of participants and their beneficiaries. No part of the corpus or income of the Plan shall revert to the City or be used for, or diverted to, purposes other than the exclusive benefit of participants and their beneficiaries.

The Plan is not reported in the financial statements of the City or the Department.

It is the opinion of the City's legal counsel that the City has no liability for investment losses under the Plan. Participants direct the investment of their money into one or more options provided by the Plan and may change their selection from time to time. By enrolling in the Plan, participants accept and assume all risks inherent in the Plan and its administration.

NOTE 6. LONG-TERM PURCHASED POWER WHOLESALE POWER TRANSACTIONS AND TRANSMISSION

***Bonneville Power Administration*—**The Department purchased electric energy from the U.S. Department of Energy, Bonneville Power Administration ("Bonneville") under a long-term contract, which expired September 30, 2001.

Until August 1, 1996, the Department was entitled to buy from Bonneville the energy required to fill the variance between its customer load and its firm power resources. The Department had a right to displace this entitlement, by payment of an availability charge. Effective August 1, 1996, the contract with Bonneville was amended, through the remaining life of the contract, to limit purchases to 195 average megawatts ("aMW") delivered flat throughout the year. The Department could displace part of this amount by paying an availability charge; almost no Bonneville energy was displaced in 2001. Power purchased under this contract was 195.0 aMW through September 30, 2001. The 1996 contract amendment required payment of a diversity fee of $2.0 million, which was amortized through September 30, 2001.

In October 2000, the Department entered into a new agreement to purchase power from Bonneville for a 10-year period beginning October 1, 2001, under the Block and Slice Power Sales Agreement. Under the terms of the agreement the Department received firm power of 152.3 aMW and 5.7 aMW in 2002 and 2001, respectively, and will receive 145.4 aMW in the third through fifth years of the contract and 259.5 aMW in the last five years of the contract as a block of power shaped to the Department's monthly net requirements, defined as the difference between projected monthly load and firm resources available to serve that load. Additional amounts of power will be purchased and received throughout the term of the contract under the Slice portion of the contract. The terms of the Slice product specify that the Department will receive a fixed percentage (4.6676%) of the actual output of the Federal Columbia River Power System. The cost of Slice power is based on the same percentage (4.6676%) of the expected costs of the system and is subject to true-up adjustments based on actual costs. The true-up adjustment billed by Bonneville for 2002 was $10.4 million, which was deferred pending rate recovery of the amount due. The Department received 322.4 aMW and 71.5 aMW of energy through the Slice product in 2002 and 2001, respectively. Under critical water conditions, the Department is expected to receive 330.0 aMW for the remaining term of the contract from the Slice product. The actual amounts of firm and nonfirm energy will vary with water conditions, federal generating capabilities, and fish and wildlife restoration requirements.

Amendments to the contract through November 2002 provide that Bonneville will pay the Department for energy savings through specified programs. The conservation augmentation program provides Bonneville funding for a portion of the Department's conservation costs in exchange for a reduction of the amount of power, by the amount of energy saved, that the Department will purchase from Bonneville. The Department received $20.0 million in cash through December 31, 2002, and will receive a total of $26.7 million through December 2003. The total amount of payments received is being recognized over the life of the Bonneville contract and $3.3 million was recognized in 2002. The reduction of energy associated with conservation augmentation was 9.0 aMW in the first year of the contract. The conservation and renewables discount program provides a Bonneville power bill credit for qualifying conservation, renewables, and low-income weatherization costs and donations to qualifying organizations. In 2002, $2.1 million was received in conservation and renewable discounts, and in 2001, $0.5 million was received.

In 1983, the Department entered into separate net billing agreements with Bonneville and Energy Northwest (formerly the Washington Public Power Supply System), a municipal corporation and joint operating agency of the state of Washington, with respect to sharing costs for the construction and operation of three nuclear generating plants. Under these agreements, the Department is unconditionally obligated to pay Energy Northwest a pro rata share of the total annual costs, including debt service, decommissioning costs and asset retirement obligations, to finance the cost of construction, whether or not construction is completed, delayed, or terminated, or operation is suspended or curtailed. The net billing agreements provide that these costs be recovered through Bonneville rates. The Department pays the amounts billed by Bonneville directly to Energy Northwest until the payment obligation has been fulfilled for the year. The billings for the remainder of the year are then paid to Bonneville. One plant is in commercial operation. Construction of the other two plants has been terminated.

***Lucky Peak*—**In 1984, the Department entered into a purchase power agreement with four irrigation districts to acquire 100% of the net output of a hydroelectric facility that began commercial operation in 1988 at the existing Army Corps of Engineers Lucky Peak Dam on the Boise River near Boise, Idaho. The irrigation districts are owners and license holders of the project, and the FERC license expires in 2030. The agreement, which expires in 2038, obligates the Department to pay all ownership and operating costs, including debt service, over the term of the contract, whether or not the plant is operating or operable.

The power purchased under this agreement was 33.0 aMW and 21.5 aMW in 2002 and 2001, respectively. To properly reflect its rights and obligations under this agreement, the Department includes as an asset and liability the outstanding principal of the project's debt, net of the balance in the project's reserve account. In July 2002, the project issued revenue refunding bonds totalling $55.985 million that bear interest ranging from 3.0% to 5.0% and mature July 1, 2004, through 2008.

***British Columbia—Ross Dam*—**In 1984, an agreement was reached between the Province of British Columbia and the City under which British Columbia will provide the Department with power equivalent to that which would result from an addition to the height of Ross Dam. The agreement was ratified through a treaty between Canada and the United States in the same year. The power is to be received for 80 years, and delivery of power began in 1986. The Department will make annual payments to British Columbia of $21.8 million through 2020, which represent the estimated debt service costs the Department would have incurred had the addition been constructed. The payments are charged to expense over a period of 50 years through 2035.

The Department is also paying equivalent operation and maintenance costs. Payments made for this purpose totalled $163,997 and $160,774 in 2002 and 2001, respectively. The power purchased under this agreement was 33.9 aMW and 35.1 aMW of energy and up to 141.0 megawatts ("MW") and 143.0 MW of peak capacity in 2002 and 2001, respectively.

In addition to the direct costs of power under the agreement, the Department incurred costs of approximately $8.0 million in prior years related to the proposed addition and was obligated to help fund the Skagit Environmental Endowment Commission through four annual $1.0 million payments. These costs were deferred and are being amortized to purchased power expense over 35 years.

Klamath Falls**—**In November 2000, the Department and the City of Klamath Falls, Oregon, entered into an agreement for the purchase of energy and capacity from the Klamath Falls Cogeneration Project, a 500 MW unit consisting of two combustion turbines fueled by natural gas and a steam generator. Under the terms of the contract, the Department receives 100.0 MW of capacity from the project beginning on the project's online date of July 29, 2001, through July 31, 2006, with an option to renew the contract for an additional five years. The Department may elect to displace all or a portion of the energy it is entitled to receive from this project in any given month. The power purchased under this agreement was 81.0 aMW in 2002 and 37.2 aMW in 2001. The Department assumes gas price and exchange rate risks for natural gas from Alberta, Canada. In April 2001, the Department entered into a separate contract that expired in December 2002 to swap variable Canadian dollar gas prices for a fixed U.S. dollar gas price.

Wind Generation**—**In October 2001, the Department entered into three agreements with Pacific Corp Power Marketing, Inc. ("PPMI") for the purchase of energy and associated environmental attributes primarily from the State Line Wind Project, a facility consisting of 399 660-kW wind turbines located in Walla Walla County, Washington, and Umatilla County, Oregon. 16.1 aMW of energy was generated in 2002. The aggregate maximum delivery rate per hour was 50 MW through July 31, 2002, increasing to 100 MW from August 1, 2002, through December 31, 2021. The Department will also receive additional firm energy with an aggregate maximum delivery rate per hour of 25 MW from January 1, 2004, through June 30, 2004, and 50 MW from July 1, 2004, through December 31, 2021, from the State Line Wind Project or another qualifying wind generation facility. PPMI may deliver, at its option, additional energy with a maximum delivery rate per hour of 25 MW beginning in 2004 from other qualifying wind generation projects.

The Department entered into a related 10-year agreement to purchase integration and exchange services from Pacific Corp. Pacific Corp receives State Line Wind Project energy at the Wallula Substation in Walla Walla County, Washington, and stores, reshapes, and delivers the power two months later. The Department also entered into another related 20-year agreement to sell integration and exchange services to PPMI.

Other Long-Term Purchased Power Agreements**—**The Department also purchases energy from Public Utility Districts (the "PUDs") No. 1 of Pend Oreille County and No. 2 of Grant County ("Grant County PUD"), under agreements expiring October 31, 2005; the Grand Coulee Project Hydroelectric Authority (the "GCPH Authority"), which includes the South, East, and Quincy Columbia Basin Irrigation Districts ("SCBID") under 40-year agreements that expire from 2022 to 2027; and the Columbia Storage Power Exchange ("CSPE"), until expiration of the agreement on March 31, 2003. Power purchased under these contracts was 81.9 aMW in 2002 and 77.4 aMW in 2001. Rates under the Grant County PUD and GCPH Authority contracts represent the share of the operating and debt service costs in proportion to the share of total energy to which the Department is entitled, whether or not these plants are operating or operable.

Three new contracts were executed in March 2002 with Grant County PUD to replace the contract expiring October 31, 2005. The agreements are effective November 1, 2005, and run concurrent with the term of the future federal relicense period.

***Transmission*—**In July 2000, the Department entered into an agreement with Bonneville for firm transmission service under Bonneville's open access transmission tariff from August 2000 through July 2025. In September 1994, the Department entered into an agreement with Bonneville for ownership of 160 MWh of Bonneville's Pacific Northwest north-south AC Intertie for $34.3 million and annual operations costs. Other transmission contracts were executed in 1995 with Puget Sound Energy for transmission of South Fork Tolt power through 2020; in 1988 with Idaho Power for transmission of Lucky Peak power through December 2007; in 1983 with GCPHA (formerly "SCBID") for transmission of the output of the GCPHA's power plants over the 40-year terms of several related power contracts; and in 1983 (as amended in 1990) with Avista for transmission of the power output of the Summer Falls and Main Canal projects through October 2005.

***Estimated Future Payments Under Purchased Power And Transmission Contracts*—**The Department's estimated payments under its contracts with Bonneville; the PUDs; irrigation districts; power exchange corporation; Lucky Peak Project; British Columbia – Ross Dam; Klamath Falls; with PPMI and PacifiCorp for wind energy and net integration and exchange services; and for transmission for the period from 2003 through 2035, undiscounted, are:

Year ending December 31,	Estimated Payments
2003	$ 266,705,346
2004	295,205,580
2005	304,098,377
2006	292,723,786
2007	300,146,326
2008 – 2012(1)	1,138,794,034
2013 – 2017	436,432,564
2018 – 2022	380,247,545
2023 – 2027(2)	129,021,666
2028 – 2032	13,172,884
2033 – 2035	641,435
	$3,557,189,543

(1) Bonneville Block and Slice contract expires October 1, 2011.
(2) Bonneville Transmission contract expires July 31, 2025.

The effects of a proposed Regional Transmission Organization and other changes that could occur to transmission as a result of FERC's proposed Standard Market Design are not reflected in the estimated future payments.

Payments in 2002 under these long-term power contracts totalled $238.2 million; and payments under the transmission agreements amounted to $30.7 million. Energy received represented 99.6% of the Department's total purchases under firm power contracts during 2002.

Wholesale Power Transactions—Power transactions in response to seasonal resource and demand variations include purchases and sales under short-term agreements and exchanges of power under long- and short-term contracts. Fluctuations in annual precipitation levels and other weather conditions materially affect the energy output from the Department's hydroelectric facilities and some of its long-term purchased power agreements. Accordingly, power transactions required to manage the Department's load and dispose of surplus energy may vary from year to year. Following are short-term wholesale power contract commitments outstanding at December 31:

	2002	2001
Wholesale power purchases outstanding:	$ 2,940,900	$ 2,880,600
Megawatt hours ("MWh")	88,800	91,800
Average contract purchase cost per MWh	33.12	31.38
Wholesale power sales outstanding:	54,206,420	42,703,580
MWh	1,570,000	1,137,000
Average contract sales price per MWh	34.53	37.56

In March 1998, the Department was certified as a scheduling coordinator with the California Independent System Operator to submit schedules and sell power and ancillary services in California. The effects of proposed Regional Transmission Organization and other changes that could occur to transmission design are not reflected in the forecast.

NOTE 7. OTHER ASSETS

Other assets comprise deferred energy management costs and other deferred charges. Deferred energy management costs, net, represent programmatic conservation costs. Seattle City Council-passed resolutions authorize the debt financing and deferral of programmatic conservation costs not funded by third parties and incurred by the Department. These costs are to be recovered through rates over 20 years.

Other deferred charges, net, consist of the following at December 31:

	2002	2001
British Columbia—Ross Dam	$ 31,448,059	$ 22,574,618
BPA Slice contract true-up payment	10,442,663	
Puget Sound Energy interconnection and substation	2,005,283	2,148,197
Skagit Environmental Endowment	2,115,225	2,232,737
Studies, surveys, and investigations	406,808	102,033
Real estate and conservation loans receivable	657,441	277,500
Unrealized losses from fair valuations of:		
Gas price swap		13,860,917
Short-term forward sales of electric energy	3,935,769	915,407
Unamortized debt expense	4,461,726	4,103,307
General work in process to be billed	1,036,565	1,124,420
Other	153,596	(888,919)
	$ 56,663,135	$ 46,450,217

Deferred power costs incurred for short-term wholesale power purchases during 2001 are expected to be recovered through rates at $8.3 million per month through 2004, pursuant to SFAS No. 71 and Ordinance 120385. Unamortized charges for the deferral of debt payments relating to Ross Dam will be amortized between 2021 and 2035. The remaining components of other assets, excluding billable work in progress, are being amortized to expense over four to 36 years.

NOTE 8. DEFERRED CREDITS

Deferred credits consists of the following at December 31:

	2002	2001
BPA conservation augmentation	$ 16,663,356	$ –
Unrealized gains from fair valuation of short-term forward sales of electric energy	396,168	14,490,436
Levelized lease payments for Seattle office	947,360	1,263,337
Prepaid capital fees	1,732,238	1,819,000
Customer deposits—sundry sales	1,070,531	1,183,708
Prepaid grants	164,785	398,000
Unspent transfer from the City	144,204	965,977
Other	98,070	135,015
	$ 21,216,712	$ 20,255,473

NOTE 9. PROVISION FOR INJURIES AND DAMAGES

The Department is self-insured for casualty losses to its property, including for terrorism, environmental cleanup, and certain losses arising from third-party damage claims. The Department establishes liabilities for claims based on estimates of the ultimate cost of claims. The length of time for which such costs must be estimated varies depending on the nature of the claim. Actual claims costs depend on such factors as inflation, changes in doctrines of legal liability, damage awards, and specific incremental claim adjustment expenses. Claims liabilities are recomputed periodically using actuarial and statistical techniques to produce current estimates, which reflect recent settlements, claim frequency, industry averages, City-wide cost allocations, and economic and social factors. Liabilities for lawsuits, claims, and workers' compensation were discounted over a period of 15 to 17 years in 2002 and 11 to 16 years in 2001 at the City's average annual rate of return on investments, which was 4.238% in 2002 and 5.341% in 2001. Liabilities for environmental cleanup and for casualty losses to the Department's property do not include claims that have been incurred but not reported and are not discounted due to uncertainty with respect to regulatory requirements and settlement dates, respectively.

The schedule below presents the changes in the provision for injuries and damages during 2002 and 2001:

	2002	2001
Unpaid claims at January 1	$ 8,090,816	$ 8,023,794
Payments	(1,474,499)	(2,664,709)
Incurred claims	3,859,925	2,731,731
Unpaid claims at December 31	$ 10,476,242	$ 8,090,816

The provision for injuries and damages is included in current and noncurrent liabilities as follows:

	2002	2001
Noncurrent liabilities	$ 7,895,490	$ 6,125,305
Accounts payable and other	2,580,752	1,965,511
	$ 10,476,242	$ 8,090,816

NOTE 10. COMMITMENTS AND CONTINGENCIES

***Operating Leases*—**In December 1994, the City entered into an agreement on behalf of the Department for a 10-year lease of office facilities in downtown Seattle commencing February 1, 1996. In early 1996, the City purchased the building in which these facilities are located, thus becoming the Department's lessor.

The Department also has two other long-term operating leases for smaller facilities used for office and storage purposes.

Expense under the leases totalled $3.5 million and $3.3 million in 2002 and 2001, respectively. Deferred credits related to the 10-year lease of office facilities in downtown Seattle totalled $0.9 million and $1.3 million at December 31, 2002 and 2001, respectively.

Minimum payments under the leases are:

Year Ending December 31,	Minimum Payments
2003	$ 3,488,500
2004	3,360,971
2005	3,371,641
2006	280,970
2007	
	$ 10,502,082

***Skagit Mitigation*—**In 1995, FERC issued a license for operation of the Skagit Project in effect through 2025. As a condition of the license, the Department has taken and will continue to take various mitigating actions relating to fisheries, wildlife, erosion control, archeology, historic preservation, recreation, and visual quality issues. The mitigation cost was estimated at December 31, 2002, to be $52.3 million of which $37.2 million has been expended.

***2003 Program*—**The estimated financial requirement for the Department's 2003 capital improvement and conservation program is $145.5 million, and the Department has substantial contractual commitments relating thereto.

***Project Impact Payments*—**Effective November 1999, the Department committed to pay a total of $11.6 million and $7.8 million over 10 years ending in 2008 to Pend Oreille County and Whatcom County, respectively, for impacts on county governments from the operations of the Department's hydroelectric projects. The payments compensate the counties, and certain school districts and towns located in these counties, for loss of revenues and additional financial burdens associated with the projects. The Boundary Project located on the Pend Oreille River affects Pend Oreille County, and Skagit River hydroelectric projects affect Whatcom County. The combined impact compensation and retroactive payments totalled $1.1 million to Pend Oreille County and $0.7 million to Whatcom County in each year of 2002 and 2001.

Endangered Species**—**Some fish species that inhabit waters where hydroelectric projects are owned by the Department or where the Department purchases power have been listed under the ESA as either threatened or endangered. In 1995, the National Marine Fisheries Service ("NMFS") developed a broad species recovery plan for the Columbia River Basin and supplemental plans in 1998 and 2000, based on biological opinions relating to the Columbia and Snake River fisheries. As a result, the Department's power generation at its Boundary Project has been reduced in the fall and winter when the region experiences its highest sustained energy demand, and the Boundary Project's firm capability has also been reduced. The U.S. Fish & Wildlife Service released a draft recovery plan for Bull Trout in late 2002. The Department has provided comments and is planning to continue to work with the agency as the plan is developed. In addition, the Department now receives power under a contract with Bonneville that provides the City with a percentage of the total Bonneville generation and the Department would thus be affected by changes in flows required in the biological opinions. In the opinion of the Department, it is unlikely that new biological opinions will result in significant changes in flows that would affect the Boundary Project, Priest Rapids, and Bonneville system. While it is unclear how other fish listings, including bull trout and chinook salmon, may affect the Department's hydroelectric projects and operations, the Department has entered into agreements that include extensive measures to protect fish and were intended to mitigate potential impacts of its projects on the Cedar, Skagit, and South Fork Tolt rivers. In addition, the Department is conducting research on these species to monitor their population health and identify potential impacts. The Department is carrying out an ESA Early Action program that will assist in the recovery of chinook and bull trout and address any further impacts on these species.

All hydroelectric projects must satisfy the requirements of the Clean Water Act to obtain a FERC license. An agreement was reached for the Newhalem Creek plant on minimum stream flows necessary to protect fish; these flows were incorporated into the FERC license issued in 1997. The Department has installed a new intake system capable of delivering the approved instream flows. The completion of the intake system, including all improvements and testing, was reported to FERC in August 2001. The new system has been performing reliably since this time.

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